Washington State

ENERGY FACILITY SITE EVALUATION COUNCIL

BP Cherry Point Cogeneration Project

Prevention of Significant Deterioration/Notice of Construction
Permit No. EFSEC/2002-01

RESPONSIVENESS SUMMARY

September 24, 2004

1. Background

On June 10, 2002, BP West Coast products LLC (BP or Applicant) submitted an Application for Site Certification (ASC) to the Energy Facility Site Evaluation Council (EFSEC or Council) to construct and operate the BP Cherry Point Cogeneration Project (Project) in Whatcom County, Washington. The submittal included an application for a Notice of Construction/Prevention of Significant Deterioration (NOC/PSD) permit and an evaluation of Best Available Control Technology (BACT). On April 22, 2003, the Applicant submitted an amended ASC, primarily addressing changes to the project's use of water. EFSEC also conducted an examination of the Application through a formal adjudicative proceeding. A Final Environmental Impact Statement (FEIS) under the Washington State Environmental Policy Act was issued in August 2004.

A preliminary approval of PSD/NOC permit No. EFSEC/2002-01 was issued for public comment on November 7, 2003. Public notice of the comment period and of a public hearing on this matter was performed by publication of a legal notice in the Bellingham Herald (11/8/2003), The Delta Optimist (11/8/2003), The Vancouver Sun (11/8/2003), and by mailing to EFSEC's interested persons list for this project, and EFSEC's minutes and agendas list (11/7/2003). Additional display advertisements regarding the location and time of the scheduled public hearing were published in The Bellingham Herald (12/6/2003), and the Delta Optimist (12/6/2003). Copies of the draft permit and associated fact sheet were made available for public reference in the Bellingham Library, the Whatcom County Library System (Blaine and Ferndale Branches), the White Rock Public Library in White Rock, B.C., the Semihamoo Library in Surrey B.C., the EFSEC offices in Olympia, Ecology's Offices in Lacey, Washington, on EFSEC's web site, and to any interested person upon request. Copies of the notices and the draft permit and fact sheet were mailed on November 7, 2003, to a list of 70 persons and stakeholders interested in this proposal.

Public comment hearings were held on this matter on December 9, 2003, in Blaine, Washington. The public comment period closed on December 12, 2003. To be considered, comments had to be postmarked, or delivered by e-mail, to EFSEC's office, no later than December 12, 2003. The period for submitting written comments was extended twice: first through January 30, 2004, and then again through March 1, 2004.

The Council received thirty seven written comment letters responding to the preliminary approval. Four persons commented on air related issues at the public hearing[1]. The topics addressed in the comments are summarized in the following table:

[1] Since the public hearings were open to comments on the draft PSD permit as well as the project in general and other related permits, oral comments were not limited to the draft PSD permit alone.

Summary of BP Cogeneration Project Public Comments

1. Doug Caldwell	1) Has new BACT technology
2. EPA R10, Jeff KenKnight	1) NOx BACT
3. Dennis Sandvig	1) Noise, 2) Odors and soot, 3) Fine Particulate
4. Karen Klokkevold	1) Toxics, 2) Noise
5. David J. Bernstein	1) Noise, 2) PM
6. Tom Stewart	1) Noise, remove refinery boilers
7. Cathy Delecourt	1) PM
8. Susan Amsberry	1) Noise, 2) Odors, 3) Impact on tourism
9. Linnea and Allen Mattson	1) Noise and soot
10. Eliana Steel-Friedlob	1) PM10 and PAH deposition to sediments, 2) acid deposition to creek, 3) Mitigation plan for direct impacts to creek
11. Veli Kalio, P.E.	1) Supports project
12. Wendy S. Steffensen for the North Sound Baykeeper program	1) PM10 and PAH deposition to sediments, 2). PBTs, 3). Acid rain. 4) modeling and monitoring of creek, 5) Toxics ASILS, 6) Toxics-Speciate PM10 and PAHs, 7) Summary of requests
13. Cathy Cleveland	1) Noise, 2) PM2.5, 3) PM deposition
14. Hugh Sloan for the Fraser Valley Regional District (comment on air impacts to DEIS)	1) Health effects of PM2.5, 2) PM emissions and method, 3) Secondary PM, 4) Refinery emissions, 5) Ammonia, 6) Start up, 7) Cumulative impacts, 8) boiler removal, 9) PM mitigation, 10) Greenhouse gasses
15. Hugh Sloan for the Fraser Valley Regional District (comments on PSD/NOC)	1) PM2.5 emissions significant, health effects, 2) PM2.5 offsets, 3) If new PM method then new PM limit, 4) ammonia, 5) SO2 monitoring and sulfur in fuel limit, 6) Greenhouse gas, 7) Offsets from refinery boilers shutdown, 8) Startup limits, 9) Curtailment during bad air days 10) Tables 3,4, and 6 of TSD wrong data
16. John Williams for The Washington State Association	1) Should require new BACT, 2) SCONOX, 3) XONON, 4) NOx BACT level, 5) NOx BACT level, 6) Actual emissions lower, 7) Ammonia, 8) Ammonia oxidizing catalyst, 9) Deposits on SCR catalyst 10) CO BACT and CO as ozone precursor, 11) CO as ozone precursor, 12) VOC BACT, 13) Startup and shutdown, 14) Cancer risks, 15) Startup and shutdown toxics, SCONOX, 16) Dry low NOx increase formaldehydes, toxics, 17) Toxics, 18) Acrolein, toxics, 19) Toxics, various loads, 20) Toxics from emergency generator and firewater pump, 21) Cooling Tower BACT
17. Bill Tadlock	1) Supports project
18. Ken Cameron for the Greater Vancouver Regional District	1) Same as letter 15
19. Steve Halpin	1) Supports project
20. Marty Klix	1) Supports project
21. Stuart Pennington	1) Supports project
22. Franklin Eventoff	1) Opposes project
23. Cathy Cleveland	1) VOC, 2.) PM emissions, 3) $10,000 research project, 4) On road specification oil, 5) Ammonia, 6) PM2.5 NAAQS
24. Kay Schuhmacher	1) Noise, visible emissions, odors, plant visibility

25. M.D. Nassichuk for Environment Canada	1) Same as letter 15
26. Mike Torpey for the BP Cherry Point Cogeneration Project	1) NOx BACT level
27. David M. Grant for Whatcom County	1) Cumulative impact, 2) PM method change
28. Doug Caldwell	1) Notify if want me at hearing
29. Alan Wilhite	1) Size
30. Ann Banks	1) Opposes project
31. Dale R. Petersen	1) Water discharge effect on herring and eelgrass
32. Mike Torpey for the BP Cherry Point Cogeneration Project	1) NOx BACT level
33. Arne Cleveland	1) Cumulative impact
34. Wallace W. Vaux	1) Supports project
35. Steve and Helene Irving	1) Local impacts on air, water, water fowl, 2) Size, 3) Ownership, 4) Heron colony, 5) Water use
36. Tom Pratum	1) PM BACT, 2) Heron colony
37. David M. Schmalz for the North Cascades Chapter of the National Audubon Society	1) Nearshore marine and fresh water systems impact, PBTs in sediments, 2) Cumulative impact on salt and fresh water systems
38. Gary Russell (Oral comment 12-9-03)	1) Removal of boilers.
39. John MacPherson (Oral comment 12-9-03)	1) Removal of boilers, 2) Greenhouse gas emissions.
40. Kathy Berg (Oral comment 12-9-03)	1) Impact of emissions on herons.
41. Patrick Alesse (Oral comment 12-9-03)	1) PM2.5 health effects, 2) Noise

The following pages summarize the comments received and indicate how the concerns expressed are addressed in the final permit issued by the Council. Some of the comments have been paraphrased or generalized to allow direct responses to the concerns expressed. Copies of the original comment letters are available upon request from the Energy Facility Site Evaluation Council, and will be available for public reference upon finalization of the permit at the following locations:

Washington State Library
Joel M. Pritchard Library
Point Plaza East
6880 Capitol Blvd
Tumwater, WA, 98504-2460
(360) 704-5200

Energy Facility
Site Evaluation Council
925 Plum Street SE, Building 4
Olympia, WA, 98504-3172
(360) 956-2121

Whatcom County Library
610 Third Street
Blaine, WA 98230

Whatcom County Library
P.O. Box 1209
Ferndale, WA 98248

Bellingham Library
210 Central Avenue
Bellingham, WA 98225-4421

Semiahmoo Library
#200 1815 152 Street
Surrey, BC V4A 9Y9
Canada

White Rock Public Library
15342 Buena Vista Avenue
White Rock, BC V4B 1Y6
Canada

2. General Comments and Responses:

A) Noise Emissions

A number of commentors indicated concern with existing noise emission from the industrial facilities located at Cherry Point, and the additional impacts of the Cogeneration Project.

Response: Noise emissions are not regulated under the PSD program. However, EFSEC has considered the noise impacts resulting from the Cogeneration Project through its SEPA review, and has documented the analysis in the Final EIS, Section 3.9. The FEIS also addresses mitigation proposed by the Applicant for noise emissions.

B) Impacts of Fine Particulate on Health of Residents

Response: The impacts of emissions of fine particulate (less than 10 microns in diameter) have been analyzed. Emissions of all regulated pollutants, including particulate matter, have been shown to be well below any applicable protective thresholds, and do not violate national or state ambient air quality standards. Ambient air Quality Standards are conservatively protective of the environment and human health.

3. Responses to Comments

Comment Letter 1: Doug Caldwell

Comment 1: Mr. Caldwell comments that his company, ISCA Management Ltd. has a technology to remove NO_X, SO_X, and heavy metals. The technology has been demonstrated on a laboratory scale at the University of British Columbia. A larger scale demonstration is anticipated. The ISCA technology should be considered for NO_X control.

Response 1: Since the ISCA technology has only been demonstrated on a laboratory scale and not on a process similar in size or design to the proposed BP Cogeneration project, EFSEC determines that it is not known and available, so cannot be considered as a BACT candidate for NO_X control.

Comment Letter 2: EPA Region 10, Jeff KenKnight

Comment 1: The Environmental Protection Agency's (EPA) Jeff KenKnight commented that the NO_X BACT emission limit in condition 6.1.1 of the draft permit should be reduced from 2.5 to 2.0 ppmdv, three hour average, corrected to 15% O_2 in order to better reflect (1) information presented in the permit application for the Project submitted by BP, (2) recent BACT determinations for similar facilities in Washington, and (3) economic and technical feasibility considerations.

Response 1: Since submitting this comment, EPA has discovered new information that distinguishes BP's Cogeneration Project from combined cycle and combined cycle cogeneration facilities operating with a NO_X emission limit of 2.0 ppmdv corrected to 15% O_2 (2 ppm NO_X). EPA is no longer confident that a properly designed and functioning selective catalytic reduction (SCR) NO_X control system at BP Cogeneration Project will be able to consistently achieve emissions reductions to below 2 ppm NO_X. Thus, EPA and EFSEC are retaining the proposed 2.5 ppm NO_X BACT emission limit.

The BP Cogeneration Project will utilize three GE Frame 7FA combustion turbines (CT) and associated heat recovery steam generators (HRSG) equipped with duct burners (DB). CT and DB exhaust combine to undergo pollution control across a SCR unit prior to exiting through a common stack. It is well known that several projects with CTs similar to those proposed by BP have been permitted at 2 ppm NO_X with averaging times ranging from one hour to one year. Within Oregon and Washington, three combined cycle projects have been permitted at 2.0 ppm 3-hour NO_X. See Table 1 below for a listing of these permitted units.

Table 1

Unit	State	Permit Authority	Permit Issue Date
Sumas Energy 2[2]	WA	EPA & WA EFSEC	04/17/03
Plymouth Generating	WA	Benton Clean Air Authority	04/20/03
Umatilla Generating	OR	Oregon Department of Environmental Quality	05/24/04

Note also that the Satsop Combustion Turbine Project in Washington has been permitted at 2.5 ppm NO_X 1-hour emission limit. In correspondence dated June 10, 1998, EPA (Region 9) stated that 2.5 ppm 1-hour limit was essentially equivalent to a 2.0 ppm 3-hour limit[3].

In addition, EPA and EFSEC are aware of eighteen F-class CTs operating today with 2 ppm NO_X emission limits. See Table 2 below for a listing of these permitted and operating units.

[2]Permit extension requested.
[3]Guidance for Power Plant Siting and Best Available Control Technology, California Air Resources Board, Stationary Source Division, September 1999. http://www.arb.ca.gov/energy/powerpl/guidocfi.pdf, http://www.arb.ca.gov/energy/powerpl/appcfin.pdf, http://www.arb.ca.gov/energy/powerpl/appdfin.pdf

Table 2

Unit	State	Startup (Year/Quarter)
1. ANP Blackstone - Unit 1	MA	2001/Q1
2. ANP Blackstone - Unit 2	MA	2001Q1
3. Lake Road Generating – LRG1	CT	2001Q3
4. Lake Road Generating – LRG2	CT	2002Q1
5. Lake Road Generating – LRG3	CT	2002Q2
6. ANP Bellingham – Unit 1	MA	2002Q2
7. ANP Bellingham – Unit 2	MA	2002Q3
8. Mystic - Unit 81	MA	2002Q3
9. Kendall Square - Unit 4	MA	2002Q3
10. Mystic - Unit 82	MA	2002Q4
11. Fore River Station – Unit 11	MA	2003Q1
12. Mystic - Unit 93	MA	2003Q1
13. Fore River Station - Unit 12	MA	2003Q2
14. Mystic - Unit 94	MA	2003Q2
15. Athens Generating - Unit 1	NY	2003Q2
16. Athens Generating - Unit 2	NY	2003Q2
17. Athens Generating - Unit 3	NY	2003Q2
18. Goldendale Energy Center	WA	2004Q3

Each emission unit's ability to comply with a 2 ppm NO_X limit could not be confirmed by solely utilizing NO_X continuous emissions monitoring system (CEMS) data provided electronically through EPA's Clean Air Markets Division (CAMD) website[4]. Each unit is subject to EPA's Acid Rain regulations, and each is required to continuously monitor, record, and report emissions to CAMD. The CAMD data provides exhaust gas NO_X concentrations and electricity or steam output (along with many other parameters) for each hour of operation. The CAMD data, however, does not distinguish emissions generated during startup or shutdown from other emissions. Multiple exceedances of the 2 ppm NO_X emission limit were recorded at multiple emissions units. Further investigation was required to determine if the exceedances occurred during startup or shutdown.

[4] http://www.epa.gov/airmarkt/emissions/raw/index.html

A majority of the turbines are located in Massachusetts and permitted by the Massachusetts Department of Environmental Protection (MA DEP). Repeated conversations with MA DEP air permit engineer, Joseph Su, indicate that all of the Massachusetts emissions units referenced above are in compliance with their respective 2 ppm NO_X emission limits, applicable at all times except startup and shutdown. Based upon this input, it appears that emissions reduction to 2 ppm NO_X is now demonstrated and available for F-class CTs and associated DBs similar to those listed above.

Although the BP Cogeneration Project's CTs and DBs are similar to the emission units listed in Tables 1 and 2, the Project's CTs and DBs will experience operating conditions not seen at the facilities noted above[5]. Like other combined cycle cogeneration projects, the Project will supply electricity to the grid and steam to customers. The fact that the Project's customer is the BP Cherry Point Refinery is significant.

The BP Cherry Point Refinery is a complex petroleum refinery with several process units and the third largest refining capacity (225,000 barrel-per-day) on the West Coast. Refinery steam demand variability is caused by the following: (1) process adjustments, process control, crude and product changes, (2) startup and stopping turbines, (3) batch cycle coker operation, (4) calciner shutdown, and (5) flare control. The levers for refinery steam header pressure control include: (1) CT load, (2) high pressure steam bypass to refinery process units (bypass steam turbine), (3) DB firing, (4) refinery boilers, and (5) combinations of the above. The goal is to maintain a constant (changes no greater than 1 – 2 psi per minute) refinery steam header pressure even through wide swings in steam flow.

The Project's CTs and DBs will be fired under variable load conditions to adjust for continuous swings in steam demand across multiple process units at the BP Cherry Point Refinery. Variable DB and CT firing rates will generate greater NO_X emissions (exit gas NO_X concentrations) and therefore limit the Project's ability to reduce emissions below 2 ppm NO_X. Stand-alone combined cycle power generation plants and cogeneration facilities with more predictable and steady-state steam loads simply enjoy more favorable operating conditions to control NO_X emissions below 2 ppm.

One such cogeneration facility is Mirant's Kendall Square Station in Cambridge, Massachusetts. Kendall Square Unit 4 (KS4) is one of only two GE Frame 7FA CTs listed in Table 2 (above) operating with a 2 ppm NO_X limit. The facility also has a 2 ppm 1-hour ammonia slip limit. Exhaust gases generated by the 2,137 MMBtu/hour (170 MW) CT and 350 MMBtu/hour DB provide heat to produce steam for utilization within three steam turbines. A portion of the leftover steam exiting each steam turbine is dispatched to 17 major customers in the Cambridge and Boston area, including Massachusetts General Hospital, the Museum of Science, Polaroid, and Biogen. It is estimated that the facility could produce up to 720,000 lb/hour of steam for sale[6].

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[5] BP Cherry Point Refinery steam demand presentation provided at EFSEC/EPA/BP Cogen meeting on January 27, 2004, and subsequently formally submitted during the public comment period on January 30, 2004.
[6] http://www.mass.gov/dte/siting/efsb99-4/final_decision.htm#N_15_

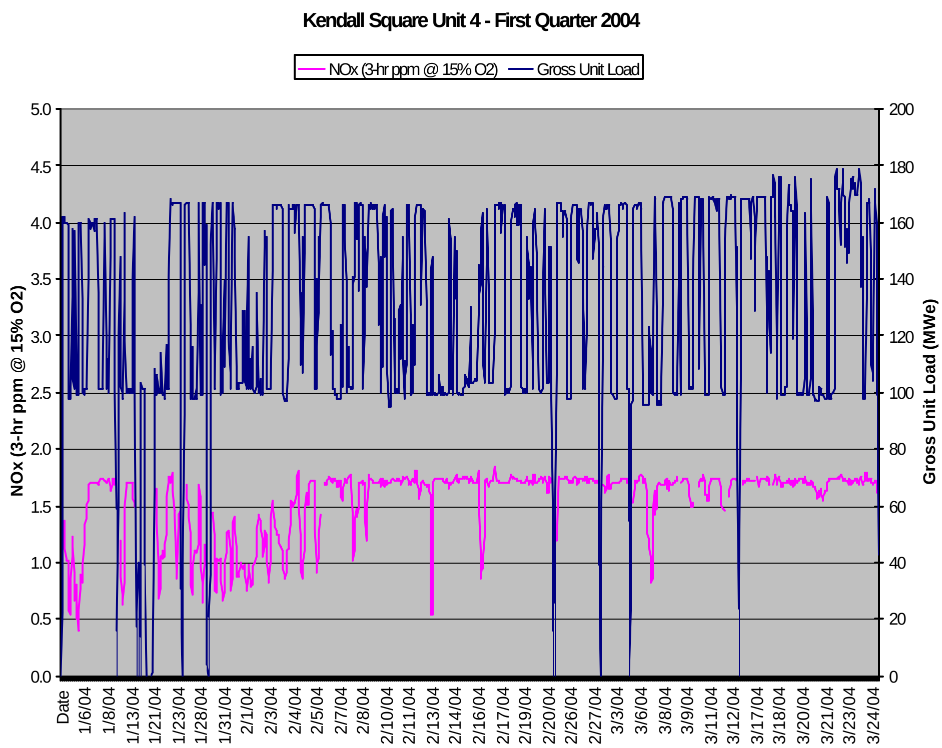
The KS4's DBs are not intended to be utilized regularly. The DBs are sized to supply steam for power augmentation in the summer and to meet maximum steam sales in the winter using steam augmentation. Power augmentation will apparently not exceed more than 1,000 hours per year as it can only be used when firing natural gas and when the ambient temperature is over 60 degrees Fahrenheit. Peak steam usage only occurs for a few days during the winter; consequently, winter duct firing would be limited. For more information regarding KS4's operating plan, consult the December 15, 2000 Massachusetts Energy Facility Siting Board Final Decision[7].

An analysis of six calendar quarters of KS4 operating data supplied by Mirant and reported to CAMD indicates a consistent pattern of CT operation at roughly only two load conditions, either full load (170 MW) or 60% load (100 MW). This is to be expected given that the facility operates the CTs as directed by dispatch in providing electricity to the grid. CAMD data indicating loads above 170 MW are assumed to be the result of converting auxiliary heat input (due to DB firing) to megawatt equivalents. The fact that megawatt loading is being reported as opposed to steam loading indicates that electric dispatch has a controlling influence regarding the operation of the CT and DB. It is EPA's understanding that changes in electric dispatch can be anticipated and generally planned for in advance so as to minimize potential for noncompliance with a fairly tight NO_X emissions limit.

Figure 1 presents KS4 first quarter 2004 CAMD data graphically. In preparing the data for presentation here, EPA chose to delete NO_X concentrations above 5 ppm given that such concentrations are the result of startup or shutdown conditions during which the 2 ppm or 2.5 ppm NO_X emission limitation is relieved. Such data would not be useful to this decisionmaking process (2.5 ppm vs 2.0 ppm NO_X BACT) and would only clutter the graph.

[7] http://www.mass.gov/dte/siting/efsb99-4/N_4_#N_4_

Figure 1



Contrast the KS4 operating data with data reported by South Houston Green Power (Figures 2, 3 and 4) located in Texas City, Texas. South Houston Green Power (SHGP) is a 50/50 joint venture involving BP Global Power and Cinergy Solutions[8]. SHGP units 1, 2 and 3 are three GE Frame 7FA CTs operating with a 3.5 ppm NO_X emission limit and a 7 ppm ammonia slip limit (at 15% O2). The units began operating the first quarter 2004, and EPA obtained first-hand knowledge of the operations on September 8, 2004[9].

Exhaust gases generated by each 2,137 MMBtu/hour (170 MW) CT and 800 MMBtu/hour DB provide heat to produce steam for utilization within the BP Texas City Refinery, BP's largest refinery in the United States with approximately 42 process units. The refinery's demand for steam approaches 2.5 million lb/hour. SHGP and an existing cogeneration plant, Power 4, supply the steam that is needed. SHGP has the capacity to generate 3.3 million lb/hour steam while Power 4 can only generate up to 1.2 million lb/hour steam. At SHGP, only one steam turbine is employed to accept up to 30% of the steam generated by the three upstream units. Most of the steam goes directly to refinery process units without diversion to the steam turbine. Each of the three units produces, on average, 700,000 lb/hour steam as evidenced by data presented in Figures 2, 3, and 4.

[8] http://phx.corporate-ir.net/phoenix.zhtml?c=74642&p=irol-newsArticle&ID=583798&highlight=

[9] September 8, 2004 conference call with Terry Harclerode of BP Products North America - Texas City. Also in attendance were BP Cogeneration Project's Mike Torpey and Mark Moore, Karen McGaffey of Perkins Coie (representing BP Cogeneration) and Rick Albright, Jeff KenKnight, Paul Boys, and Dan Meyer of EPA.

SHGP DBs are utilized regularly to track fluctuating steam demand. No one unit is based-loaded (steady firing) and no one unit is designated as the swing unit (variable firing).

As evidenced by the data from SHGP, the fluctuations in steam load appear to be continuous and unanticipated. Such fluctuations are managed by a combination of several operating control mechanisms, not the least of which is duct firing. BP Texas City indicates that the very best SCR system on the market was purchased to control NO_X emissions from the three units at SHGP. Despite employing a state-of-the-art SCR control system, continuous firing of the large 800 MMBtu/hr duct burners (higher polluting than CTs) at SHGP is making it difficult for the facility to comply with its comparatively less stringent 3.5 ppm NO_X limit. These challenges can be expected at BP Cogeneration as well given its similar design.

Like SHGP, BP Cogeneration will be employing three GE Frame 7FA combustion turbines along with one steam turbine. Whereas SHGP's steam condensing turbine[10] received only up to 30% of steam exiting the upstream HRSGs, BP Cogeneration's steam condensing turbine will be designed to receive nearly all the steam created upstream. Upstream, each HRSG is supplemented with a comparatively smaller 105 MMBtu/hour DB. Roughly 33% of the steam exiting the steam turbine (510,000 lb/hour) at BP Cogeneration will proceed on to the refinery, whereas 66% will be condensed and sent back to the HRSG.

Given these design parameters, it appears that BP Cogeneration will not be as focused on steam generation for the benefit of downstream refinery consumption as compared to SHGP's dedication to tracking steam demand. Still, the uncertainty associated with fluctuating and unanticipated steam demand and the potential need to employ DB unexpectedly is compelling. EPA and EFSEC are not confident that BP Cogeneration will be able to achieve continuous compliance with a 2 ppm NO_X emission limit even after employing the state-of-the-art SCR system. Thus, EPA and EFSEC agree to retain the 2.5 ppm NO_X BACT emission limit.

[10] http://www.dresser-rand.com/insight/v5no1/gvision7.asp

Figure 2

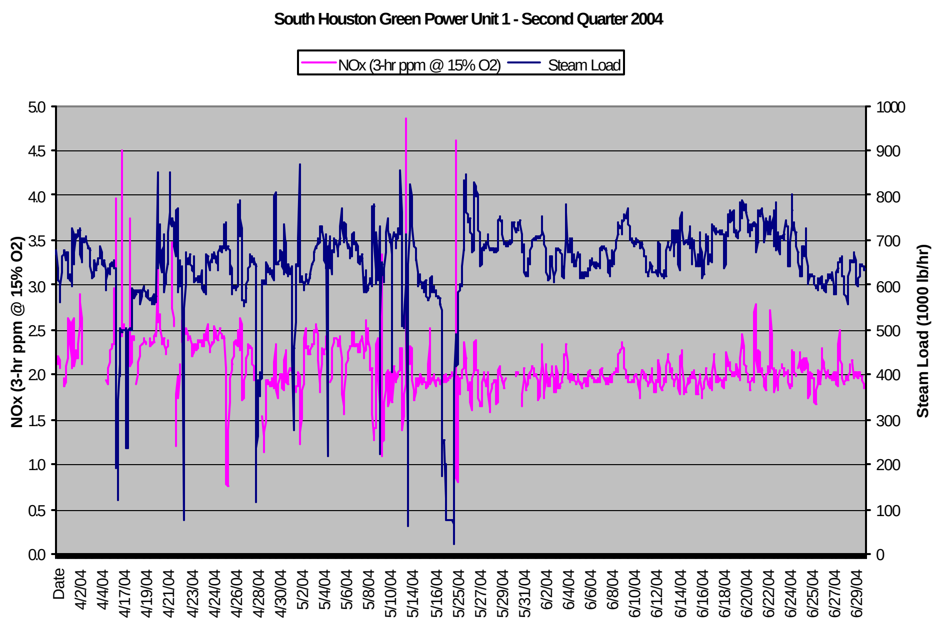


Figure 3

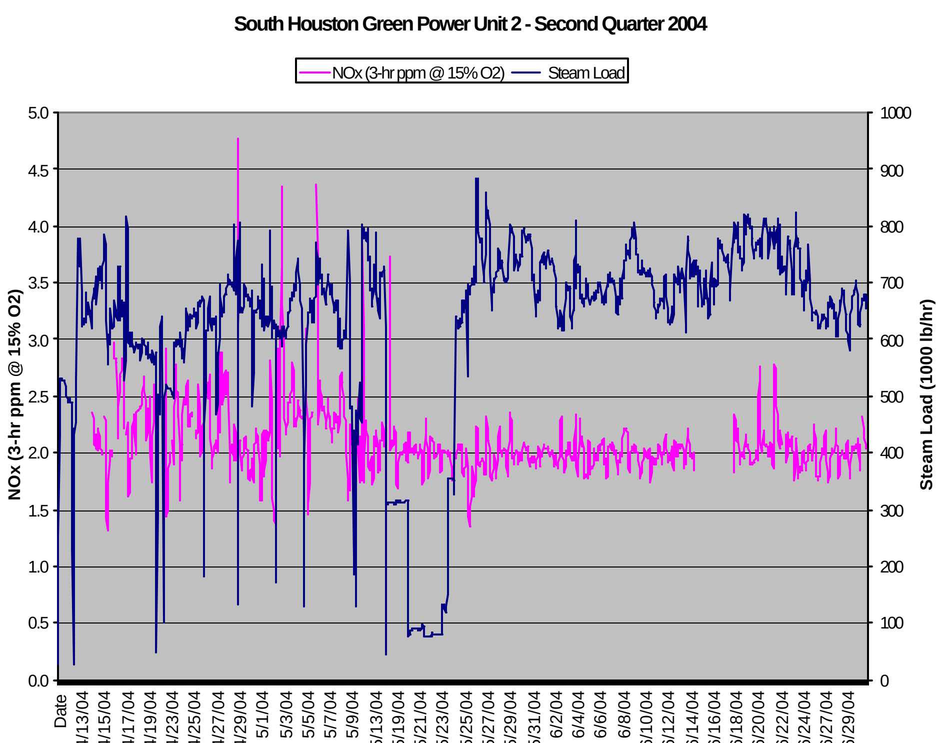
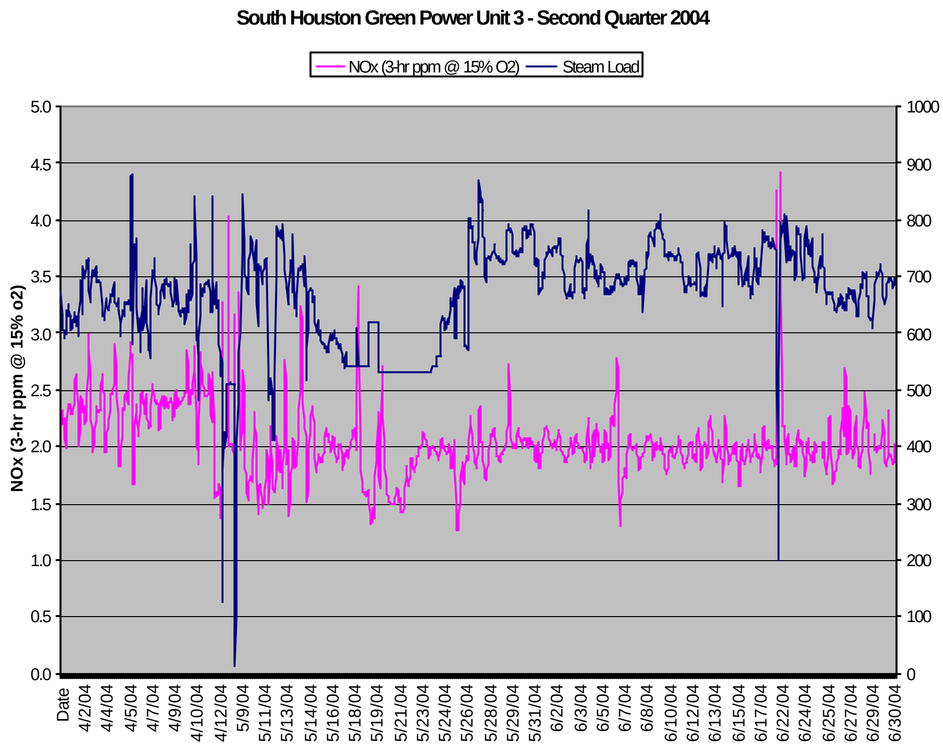


Figure 4



Comment Letter 3: Dennis Sandvig

Comment 1: Mr. Sandvig, a resident that lives in the Cottonwood area of Birch Bay raises concerns about existing noise produced by the BP Refinery, and the impact from additional noise from the Cogeneration Project.

Response 1: Please see General Comment Response A above.

Comment 2: Mr. Sandvig relates the incidence of odors and of soot and particulate deposits on his residential property, and expresses that the Cogeneration Project will add to these impacts.

Response 2: The Cogeneration project will combust natural gas, a very clean fuel, in the turbines in a very efficient manner. Particulates emitted are expected to be very fine and would not be deposited as soot in nearby communities. The oxidation catalyst will control any unburned hydrocarbons resulting from combustion of the natural gas, which will effectively control odor emissions.

Comment 3: Mr. Sandvig expresses concerns about the health hazards of the fine particulate emissions from the Cogeneration Project.

Response 3: Please see General Comment B above.

Comment Letter 4: Karen Klokkevold

Comment 1: Ms. Klokkevold expresses concerns that toxins present in the air emissions from the Cogeneration Project will impact recreational users of the nearby Trillium Property.

Response 1: The facility will burn natural gas, the cleanest fossil fuel available for power generation. The facility will employ Best Available Control technology to control emissions, including an oxidation catalyst for control of organic compounds that a re not fully burned in the combustion turbines. The impact of Toxic Air Pollutants has been analyzed as required by state law, and was found to be well below thresholds of impacts to health.

Comment 2: Ms. Klokkeveld raises concerns about additional noise emissions from the facility.

Response 2: See response to General Comment A above

Comment Letter 5: David J. Bernstein

Comment 1: Mr. Bernstein expresses concerns about the impact of existing and future noise emissions on his personal and commercial recreational properties.

Response 1: Please see general Comment A, above.

Comment 2: Mr. Bernstein expresses his concerns about particulate emissions on children.

Response 2: Please see response to General Comment B. The Ambient Air Quality Standards established by the U.S. Environmental Protection Agency are designed to meet the protective needs of more sensitive populations, including children and the elderly. EFSEC has insured that this project uses the most stringent emissions control technologies to comply with all state and federal regulations.

Comment Letter 6: Tom Stewart

Comment 1: Mr. Stewart acknowledges the proposal to remove refinery boilers should the Cogeneration project Move Forward. Mr. Stewart requests that the Calciner also be shut down to further reduce existing emissions and noise.

Response 1: Please see General comment A above regarding noise emissions. With respect to removal of existing emissions sources at the Refinery, for purposes of regulatory review, removal of the refinery boilers was not included in the analysis of the emissions impacts form the Cogeneration Project. The Applicant demonstrated that even without removing the boilers, the project was protective of all air state and federal air emissions thresholds. The Applicant, through a settlement agreement with the Counsel for the Environment, agreed to remove three refinery boilers should the Cogeneration project proceed to construction and operation. Removal of the boilers would be required though the Site Certification Agreement issued to BP for the

Cogeneration Project. Additional removal of the Calciner is not within the regulatory scope of the PSD program.

Comment Letter 7: Cathy Delcourt

Comment 1: Ms. Delcourt, a resident of the Fraser Valley, expresses concerns about the impact of fine particulate that can travel long distances, and potentially impact the Fraser Valley which is home to a lot of agriculture. She asks what will be done to eliminate this problem.

Response 1: The Applicant has analyzed the long distance impacts of the Cogeneration Project emissions, including impacts on the Fraser Valley. If considered alone, the particulate emissions from the Project are well within any Canadian regulatory standards and objectives. In addition, the Applicant ahs committed to removing three existing boilers at the BP refinery should the Cogeneration Project proceed to construction. Removal of these boilers will decrease the overall impact of the project particulate emissions in both Whatcom county and Canada.

Comment Letter 8: Susan Amsberry

Comment 1: Ms. Amsberry expresses concerns about noise impacts from the proposed facility.

Response 1: See general comment A.

Comment 2: Ms. Amsberry expresses concerns about the existing smell and particulate problems in Birch Bay and hopes that they will not be made worse by the Cogeneration Facility.

Response 2: Please see response to Letter 4, Comment 1.

Comment 3: Ms. Amsberry expresses concerns about potential adverse impacts to the Birch Bay tourist community due to increased noise and pollution.

Response 3: The PSD program requires an analysis of growth related activities associated with the facility. As indicated in finding No. 20 of the PSD approval, no significant effect on industrial, residential or commercial growth is anticipated as a result of this Project. Also, as indicated in the response to General Comment B, the Project meets all applicable regulatory standards.

Comment Letter 9: Linea and Allen Matson

Comment 1: Allen and Linea Mattsen, residing in the nearby neighborhood of Cotton Wood, Birch Bay, express concerns about the existing undesirable noise level and existing black sooty ash fall, and the impacts of breathing such particles.

Response 1: Please see responses to General Comment A, General Comment B, and Letter 3, Comment 2. Through the PSD permitting and the Site Certification processes, EFSEC will require that the project be constructed with the least impacts to the environment and local residents as possible.

Comment Letter 10: Eliana Steele-Friedlob

Comment 1: Ms. Steele-Friedlob is concerned that PM10 and PAH pollutants can potentially degrade habitat in Terrell Creek. She requests that deposition of air pollutants into marine and fresh water habitats be modeled, and that the permit require biannual sediment monitoring for pollutants within the deposition zone.

Response 1: Modeling of deposition is not warranted because natural gas, a very clean fuel, is being burned, and the emissions resulting from natural gas combustion are not considered a significant deposition source of PM10 and Polycyclic Aromatic Hydrocarbons (PAHs). The particulate matter emissions from the Cogeneration Project, though modeled as PM10 for regulatory purposes, are less than PM2.5. This type of very fine particulate behaves more like a gas, and will disperse in a wider area, and will not deposit close to the site and in Terrell Creek as much as larger particles would.

The project will employ BACT emissions control technology to further limit emissions of PM10 by use of high technology lean pre-mix dry low NOx burners and requiring best operation practices. Organic compound emissions, such as PAHs are minimized by the following: 1) use of lean pre-mix dry low NOx burners that combust the organics present; and 2) post combustion controls such as the oxidation catalyst which further reduce organic compound emissions.

Comment 2: Emission of NOx and SO2 are not linked to the biology of the Terrell Creek watershed and the potential impacts of acid rain on salmon that may be present. Monitoring should be required to ascertain to effects of NOx and SO2 emissions from the Cogeneration project on nearby freshwater ecosystems. If disruptions to the system are identified, emissions should be curtailed and mitigation of impacts should be mandatory.

Response 2: NOx emissions from the project are minimized through the use of clean burner technology (see response to Comment 1 above), and through the use of BACT (SCR technology). SO2 emissions will be very low because the natural gas fuel used contains minimal sulfur compounds. Unlike coal or fuel oil, natural Gas is the lowest sulfur containing fuel available, and is generally not considered a source of acid rain in Class II areas. Monitoring of this source is not warranted through the PSD permitting program.

Disruptions to the freshwater ecosystem from the Cogeneration Project emissions are highly unlikely and not anticipated. However, through the Site Certification process, the Council has jurisdiction to require cessation of operations and mitigation of impacts should a *direct* impact to nearby fresh water ecosystems from the Cogeneration Project be identified in the future.

Comment 3: Ms. Steele-Friedlob requests that a compensation plan be developed to outline the unacceptable biological and physical effects that might occur due to the Cogeneration Project Emissions, and that associated mitigation and curtailment measures be identified in the plan.

Response 3: Please see response to Comment 2. Because of the nature of the Cogeneration Project, and the clean fuel that would be burned, unacceptable biological and physical effects have neither been identified through the PSD permitting process, nor are such effects expected. Again, through the Site Certification process, the Council has jurisdiction to require cessation of operations and mitigation of impacts should a *direct* impact to nearby fresh water ecosystems from the Cogeneration Project be identified in the future.

Comment Letter 11: Veli Kalio, P.E.

Comment: Ms.Veli Kallio supports the project and comments that it meets all regulatory requirements.

Response: Thank you for your comments.

Comment Letter 12: Wendy S. Steffensen, North Sound Baykeeper Program

Comment 1: Ms. Wendy S. Steffensen, for the North Sound Baykeeper Program, comments that PM10 and PAH pollutants can deposit close to the source and potentially degrade nearby fresh and marine water habitats. The commentor requests that that freshwater and sediment concentrations be compared with water quality and sediment limits. She requests that deposition of air pollutants into marine and fresh water habitats be modeled, and that the permit require biannual sediment monitoring for pollutants within the deposition zone.

Response 1: Please see responses to Letter 10.

Comment 2: Emissions of Persistent Bioaccumulative Toxins (BPTs) were not considered.

Response 2: Under New Source Review in Washington state, PBTs are considered as Toxic Air Pollutants (TAPs), and the impacts of TAP emissions are regulated pursuant to Chapter 173-460 WAC. As noted in Table 7 of the Technical Support Document (TSD), toxic air pollutant emissions, including PBT's such as Cadmium, were analyzed and modeled against the standards of Chapter 173-460 WAC, and were found to below the levels of concern that require additional modeling or monitoring.

Comment 3: Emission of NOx and SO2 are not linked to the biology of the Terrell Creek watershed and the potential impacts of acid rain on salmon that may be present. Monitoring should be required to ascertain to effects of NOx and SO2 emissions from the Cogeneration project on nearby freshwater ecosystems. If disruptions to the system are identified, emissions should be curtailed and mitigation of impacts should be mandatory.

Response 3: Please see response 2 to Letter 10 above.

Comment 4: The commentor lists the requests for modeling and monitoring made in comments 1 through 3 above. The commentor requests that methods to reduce discharges of PBTs be assessed and implemented prior to construction of the Project.

Response 4: Please refer to responses 1 to 3 above, and responses to comment letter 10.

With regard to reduction of PBT discharges in air emissions, they are being minimized by the following: 1) use of a clean fuel (natural gas), 2) use of lean pre-mix dry low NOx burners that combust the organics present; and 3) post combustion controls such as the oxidation catalyst which further reduce organic compound emissions. These reduction technologies are incorporated into the plant design and will be required prior to construction.

Comment 5: The commentor requests that the combined concentration of pollutants be compared to the ASIL limits established in Chapter 173-460 WAC. The commentor also requests that all other sources in the Cherry Point Area be included in such an analysis also.

Response 5: The maximum predicted concentrations of Toxic Air pollutants, including PBTs, were modeled and compared against the corresponding Acceptable Source Impact Level (ASIL) as required by Toxics New Source Review. The ASILs are health protective thresholds, well below concentrations which are known to cause harm to human health and the environment. If concentrations are below the ASIL, no additional study is required by state regulation. If concentrations exceed the individual ASILs, a "Second Tier" health assessment must be performed to determine if the emissions and resulting ambient concentrations will threaten human health or increase human health risks. The Second Tier analysis may be required to include consideration of the impact of other existing sources of the compound on potential health risks. Since no ASILs were exceeded for this Project, additional analysis is not required.

Comment 6: The commentor indicates that PM10 and PAH should be speciated, and the individual components analyzed. They should be regulated as a group and as individual species. The commentor requests that the annual emissions of each individual pollutant be included in the TSD.

Response 6: As required by toxics new source review, the components of PM10 were analyzed both as "groups" and as their individual components, and PAHs were analyzed as a group. The emissions of toxic air pollutants, be they as particulate matter or as gases, were analyzed as required under Chapter 173-460 WAC. As indicated in the comment, Table 7 of the TSD addressed the analysis and concluded that TAP emissions were below the level for concern. The PSD permit application included a speciation of toxic air pollutants in Volatile Organic Compounds (VOC) and PM10 compounds with their annual emission rates. This information is included in this response as Attachment 1. It should also be noted that of the 261.1 tpy of PM10 emitted, not all of this mass is considered a "toxic air pollutant". Attachment 1 indicates that the toxic portion of PM10 is less than 1500 lbs/year (0.75 tpy).

Comment 7: The commentor summarizes the requests in comments 5 and 6.

Response 7: Please refer to responses 5 and 6 above.

Comment Letter 13: Cathy Cleveland

Comment 1: Ms. Cathy Cleveland expresses concerns about existing noise form the Refinery and additional noise form the Cogeneration Project.

Response 1: See general Response A

Comment 2: PM 2.5 and health issues.

Response 2: See general response B.

Comment 3: Existing Particulate deposition from the BP refinery.

Response 3: See response 2 to Comment Letter 3.

Comment Letter 14: Hugh Sloan, Fraser Valley Regional District

Note: During the comment period on the draft PSD/NOC permit, the Fraser Valley Regional District's re-submitted the Greater Vancouver Regional District's comments on the Draft Environmental Impact Statement. The Draft PSD/NOC permit and associated technical Support Document addressed most of the issues directly. Responses to the comments to the Draft EIS have been addressed in the Final EIS. The FVRD also submitted comments on the draft PSD/NOC permit, which are addressed in letter 15.

Comment 1: Health effects of PM 2.5 emissions.

Response 1: Please refer to General Response B. The consideration of health impacts is beyond the scope of PSD review if a project has demonstrated compliance with applicable regulatory standards. However, a discussion of health effects from PM 2.5 has been included in the Final Environmental Impact Statement (FEIS).

Comment 2: The analysis of impacts should not have included the adjustments for errors inherent in PM10 measurement methods.

Response 2: For purposes of the PSD review, adjustments due to errors inherent in the test methods, were not considered, and maximum potential emissions were analyzed for regulatory purposes.

Comment 3: There is uncertainty in the conversion rates of NOx and SO2 to particulate matter, and a range of conversions should have been used.

Response 3: The Applicant considered conversion of NOx and SO2 to obtain an estimate of what actual emissions would be. The analysis including the reduction of secondary particulate emissions as a result of removal of refinery boilers was not considered in the PSD review of the project. For regulatory purposes, maximum potential emissions were used to assess short and long range impacts as required under state and federal law and regulation.

Comment 4: In order to address the worst case, modeling of PM emissions should ignore any refinery offsets or PM adjustments, especially for short term exposures.

Response 4: Maximum potential emissions for both short term and long term periods were considered for regulatory purposes – refinery reductions and PM adjustments were not considered for PSD regulatory purposes.

Comment 5: Regarding ammonia emissions, it would be beneficial to:

a) Report the maximum ammonia concentration in Canada;
b) Give consideration to the formation of additional ambient particulate due to this ammonia source.

Response 5:

a) Under state new source review requirements, ammonia is considered a Toxic Air Pollutant under Chapter 173-460 WAC, and is compared against the respective ASIL to assess potential impacts to human health. For federal PSD regulatory purposes, the impact of ammonia emissions is considered through visibility and nitrogen deposition in protected federal Class I areas. Federal regulations do not require assessment of ambient ammonia concentrations beyond the requirements of Chapter 173-460 WAC. The maximum ammonia impact in Whatcom County was modeled at 2.8 ug/m3, near the Canadian border between Blaine and Sumas. The PM10 24-hour average isopleths (reported in the Applicant's prefiled testimony to EFSEC, Exhibit 22) indicate that within several kilometers into Canada, the impact will drop to a range of 50% to 20% of the maximum.

b) Under the PSD program, long range impacts (specifically to Class I areas) are analyzed using the Calpuff model. Visibility and nitrogen deposition modeling does take into account the formation of secondary particulate from ammonia and NOx and SO2 precursors. In running the Calpuff model, the applicant did not restrict the amount of ammonia present in the ambient air for secondary particulate formation, regardless of the source (existing background or from the Project). This means that there probably is enough ammonia in the current background levels to fully react all NOx and SO2 to secondary particulate and additional ammonia from the project would not result in additional secondary particulate in the atmosphere. In running the Calpuff model, the Applicant assumed that all NOx and SO2 emitted by the project would react to form secondary particulate.

Comment 6: The EIS should contain the emissions from startup worst case scenarios.

Response 6: Emissions from startup were considered in developing the PSD/NOC permit. For regulatory purposes of the PSD and state new source review programs, maximum concentrations during startup (including maximum background) were compared against applicable ambient air quality standards and objectives for both the U.S. and Canada. It was determined that the standards and objectives would not be violated. Table 4 of the TSD included the data on which this determination was based.

Comment 7: The commentor indicates that the EIS should consider the percentage contribution of the Cogeneration project annual emissions to the total pollutant emissions in Whatcom County and Fraser Valley Airsheds.

Response 7: Under PSD and state new source review, annual emissions from the Project are used to determine the level of review required. Impact to the airshed is evaluated through modeling to determine compliance with applicable ambient air quality standards, Significant Impact Levels, and protection of PSD increment in an attainment area. Comparison of the Cogeneration project emissions to total emissions in the Whatcom County and Fraser valley Airsheds has been addressed in the Final EIS.

Comment 8: Consideration of Refinery Boiler Removal emission reductions on decision making to require removal of the boilers.

Response 8: For regulatory PSD and state new source review, emissions reductions resulting from refinery boiler removal were not considered in the permitting process. All analyses were based on maximum potential emissions from the Cogeneration Project, and as indicated in the TSD, the emissions were in compliance with all regulatory standards and objectives. The Site Certification Agreement will require shut down and removal of the boilers should the Cogeneration Project be constructed and operated.

Comment 9: The commentor states that PM2.5 emissions from the project are a significant addition to the airshed, and will result in some addition to ambient air concentrations. The Applicant proposed no mitigation to minimize the impacts of PM emissions from the operation of the proposed power plant.

Response 9: The commentor is correct, that Cogeneration Project emissions will result in some increase in ambient PM2.5 concentrations. Please refer to Response 7, above. If impacts to air quality related values established under the PSD and state new source review programs are below regulatory impact levels, additional mitigation for emissions is not required.

Comment 10: The commentor addresses the impacts and mitigation of greenhouse gas emissions.

Response 10: Greenhouse gas emissions are not regulated under federal PSD and state new source review programs. Mitigation of greenhouse gas emissions has been addressed by EFSEC in the Site Certification Agreement.

Comment 11: Attachment A is a more detailed explanation in support of the above comments.

Response 11: EFSEC appreciates the consideration given to the issues by the FVRD. Please refer to the responses above for applicability of these comments to PSD/NOC permitting. Reponses to the issues expressed have been presented in the Final Environmental Impact Statement.

Comment Letter 15: Hugh Sloan, Fraser Valley Regional District

Comment 1: Mr. Hugh Sloan, for the Fraser Valley Regional District, considers that the PM2.5 emissions from the Project are a significant addition to the overall PM 2.5 concentrations in the Whatcom County and Fraser Valley airsheds. Worst case increases in ambient PM emissions associated with Project would be expected to lead to increased adverse health effects among some Canadian and US residents. The commentor requests that permit emission limits be evaluated and set after a more thorough analysis of the PM2.5 concentrations has been performed.

Response 1: Under State and Federal air permitting requirements, human health impacts are taken into consideration when ambient air quality standards are established for regulated pollutants. In establishing national ambient air quality standards for PM2.5, the U.S. EPA has taken into account health risks. The Applicant has demonstrated that the emissions form this Project do not violate any U.S. or Canadian standards and objectives, and are therefore within acceptable health impact limits.

Comment 2: The PSD permit and/or Site Certification Agreement should consider requiring offsets for PM 2.5.

Response 2: The Project is proposed in an area that is in attainment for all regulated criteria pollutants. The project has demonstrated that all air quality related values will be protected. Offsets are only required for proposals in non-attainment areas.

Comment 3: If an alternative method for measurement of particulates is approved, the PSD permit limits for PM10 should be revised accordingly.

Response 3: EFSEC appreciates this “heads up” comment. If a PM10 measurement method change is proposed in the future, an appropriate revision in the PM10 limit will be required as a part of the permit modification.

Comment 4: Because SO2 and Ammonia are precursors to secondary particulate, continuous monitoring should be required for these pollutant emissions instead of annual stack testing.

Response 4:

Ammonia: The commenter is incorrect in the frequency of annual stack testing for ammonia being reduced to 5 year intervals. There is no provision for reducing the frequency of annual stack testing for ammonia.

As indicated in NOC Approval condition 2.1, the permittee is required to establish a correlation between the heat input rates of the gas turbines and associated HRSG, the SCR ammonia injection rate, and the corresponding ammonia (NH3) emission concentration at the exhaust point. NOC Approval Condition 2.3 requires that this correlation be updated annually. NOC permit Approval Condition 6.1.2 requires daily calculation of ammonia emissions using the correlation, and inclusion of the data collected in the quarterly report to EFSEC.

SO2: In addition to annual stack testing, (which may be reduced after 3 years of testing, as noted by the commenter), PSD permit Approval condition 10.4 requires daily calculation, and quarterly reporting, of daily SO2 emissions based on fuel use and fuel composition data supplied to the permittee. Because sulfur emissions are only related to sulfur input in the natural gas fuel, daily monitoring of fuel sulfur content is deemed sufficient for sulfur compound emission reporting. An SO2 Continuous Emission Monitoring System (CEMS) instrument would not provide enough additional benefit to justify cost of installation and operation.

Comment 5: The permit should set a 1-hour concentration limit of 1 ppm for SO2 and should require monitoring of fuel use consistent with the Sumas Energy 2 PSD permit.

Response 5: Sulfur is a pass through pollutant. The sulfur emitted in the exhaust is equal to the sulfur in the fuel input to the plant. BACT for SO2 is use of natural gas fuel. The quality of the natural gas supply will determine emissions from this project. Daily monitoring of fuel supply is required, and is deemed sufficient for compliance monitoring purposes when used in conjunction with annual stack testing.

Comment 6: The PSD permit does not consider greenhouse gas emissions. GHG emissions will be dealt with in the Site certification Agreement.

Response 6: The commentor is correct.

Comment 7: The PSD/NOC permit does not deal with emission reductions (offsets) resulting from removal of the refinery boilers. The permits and/or the Site certification Agreement should include conditions for decommissioning of the refinery boilers, and amendment of the refinery permits to account for the emissions decreases.

Response 7: As indicated in response 8 to letter 14, for regulatory purposes refinery reductions can not be counted as enforceable offsets for PSD permitting purposes for this Project. The Site Certification Agreement will require removal of the boilers if the Cogeneration Project is constructed and operated. EFSEC does not have jurisdiction over the Refinery PSD permit. BP and the appropriate regulatory agency (Northwest Air Pollution Authority and/or Ecology) will amend the refinery permits as needed to take into account removal of the boilers.

Comment 8: The commentor requests that conditions for startup include: a) relaxed limits for NOx, CO and VOC emissions instead of relieving limits altogether; b) revise approval conditions 14.4.1, 14.5.1 and 14.6.1 so that time limits established in condition 14.1.2 are not superceded; and c) limit startups to periods with good dispersion.

Response 8:

a) During startup the only means for pollutant emission control are employing the optimum startup procedures for the turbines, HRSGs and associated equipment. PSD permit Approval Condition 13 requires that optimum procedures be established for startup and shutdown in an Operations and Maintenance Manual, and followed. Emissions during startup are then measured and counted towards the annual limits. See letter 14, response 6 for further discussion of startup emissions.

b) The comment is noted. PSD Approval conditions 14.4.1, 14.5.1 and 14.6.1 have been revised to remove any potential conflict with PSD Approval condition 14.1.2, by the addition of the following sentence: " Time in Startup mode is limited by Condition 14.1.2."

c) Emission limits are set to assure compliance regardless of dispersion conditions, anytime during the year. The modeled startup emissions (see Tables 3 and 4 of the TSD) reflected worst case meteorological conditions in two ways: 1) Project emissions were based on the maximum emissions modeled, taking into account meteorological conditions over several years; and 2) background concentrations were maxima measured over several years. Based on these worst case conditions, no standards and objectives for ambient air quality were violated. Under federal and state new source review requirements, limitation of operations is only considered if necessary in non-attainment situations.

Comment 9: The permit should require curtailment of plant operations in the event that air quality shows signs of deterioration in the Lower Fraser valley.

Response 9: A formal process has been established in Washington State to alert the public to "Air Pollution Episodes", and to control pollution to resolve episodes that may endanger human health. EFSEC has the authority under its regulation(WAC 463-39-230(5)) and its statute (chapter 80.50 RCW) to require its regulated source to stop operations in such an event. Local air quality authorities have authority to require reduced operations of many sources of air pollution if air quality conditions become adverse to health. Reductions from fireplace burning is typically the first emission reduction requested or required under Chapter 173-433 WAC, but reductions from industrial sources may be required under Chapter 173-435 WAC if the conditions of the air quality episode are met.

Comment 10: Tables 3, 4 and 6 of the TSD show incorrect data for background -hour PM10 concentrations, and 1-hour CO concentrations.

Response 10: The comment is noted. The changes do not affect conclusions regarding compliance with applicable ambient air quality standards.

Comment Letter 16: John Williams

Comment 1: Mr. John Williams, for the Washington State Association, calls upon the EFSEC to require the applicant to submit a new BACT/PSD analysis.

Response 1: This comment is general in nature, and seems intended to be a summary of the intent of the comments that follow it. EFSEC will treat it as such and respond to the comments that follow it.

Comment 2: SCONOX should have been further considered as BACT technology.

Response 2: SCONOx was evaluated in both the application and Technical Support Document Section 2.2.1.3. Its use on several small turbines, and permitting on several large turbines was discussed. Its rejection in favor of SCR in the Three Mountain Island permit was discussed. New information since the writing of the BP application revealed that at another California large turbine project where it was permitted as an option to SCR, the Otay Mesa Project, SCR was chosen as the NOx control, and the final permit eliminated any mention of, or requirement for the installation of, SCONOx.

SCONOx was eliminated as a NOx control technology for the BP Cogeneration project through the "top down" BACT process economic analysis. A cost quote obtained directly from the SCONOx technology supplier, EmeraChem, indicated a $22,900 dollars per ton NOx removed annualized cost. Recognizing the multipollutant removal capability of SCONOx , the annual cost to removal NOx, CO, and VOC was calculated at more than $12,000 per ton. The SCR and oxidation catalyst systems were much more cost effective to achieve the same emission reductions, so SCONOx was defeated because of its high cost.

Comment 3: XONON should have been considered as BACT technology.

Response 3: The draft PSD permit findings outlined the BACT chosen for this project. The TSD did include a discussion of SCONOX (Section 2.2.1.3) and XONON (2.2.1.2). The analysis determined that XONON did not meet the requirements for commercial availability for the size of combustion turbine proposed for this Project.

Comment 4: SCR with 2.0 ppm NOx on 3 hour rolling average or 2.5 ppm as a one hour rolling average should have been considered for NOx BACT.

Response 4: See Letter 2, Response 1.

Comment 5: The commentors express that a complete BACT analysis was not performed to consider SCR technology with NOx reductions to 2.0 ppm with short term averages. The commentors cite a number of BACT and LAER decisions requiring SCR control to 2.0 ppm. BACT should be SCR with 2.0 ppm NOx emissions, 3 hour rolling average, or 2.5 ppm one hour rolling average.

Response 5: Letter 2, Response 1

Comment 6: The commentors propose the use of SCR technology, with more catalyst and more frequent catalyst replacements, with lower ammonia slip rates, so that NOx emissions of 1 ppm and Ammonia emissions of 2 to 3 ppm are attained. The commentors give several examples of recent facilities required to limit ammonia emissions to such levels.

Response 6: Thank you for this information. It is anticipated that actual NOx and ammonia emissions will be lower than their permitted limits, probably in the range noted by the commenter.

Comment 7: Actual Experience with Ammonia at natural gas combustion turbine facilities has shown that NH3 emissions are less than 5 ppm. EFSEC should have conducted a top down TBACT review of achievable ammonia emission limits.

Response 7: A review of ammonia emission limits in the RBLC database and from other recent permit information available demonstrated that the 5ppmdv permit limit was appropriate.

Comment 8: EFSEC should consider SCR technology plus downstream Oxidizing Catalyst, and the PSD permit should be modified to limit ammonia emissions to 2 ppm.

Response 8: See response 7 above.

Comment 9: Secondary Particulates deposit within the HRSG because of reactions between ammonia, SO2 and NOx, and causes maintenance problems.

Response 9: Thank you for your comments.

Comment 10: CO limits less than 1 ppm should be set because CO emissions less than 1 ppm have been routinely achieved. A conventional oxidation catalyst would reduce toxics emission, in addition to CO. Furthermore CO should be controlled to avoid increases in ozone which could aggravate the potential ozone compliance problems in the Columbia River Gorge.

Response 10: It is expected that *actual* emissions achieved will be less than the emissions limit set, as has been demonstrated by the facilities cited. The 2.0 ppm limit is appropriate, as compared to the lowest limit cited in the comment (1.8 ppm over 1 hour at the Newark Bay Cogeneration Facility). The Cogeneration Project will use a conventional oxidation catalyst, as required by BACT.

Based on the dispersion modeling performed for this project, the BP Cogen Project would not contribute to the ozone compliance problems in the Columbia River Gorge which is more than 200 miles away.

Comment 11: CO emissions from the BP Cogen project, as precursors to ozone, could impact the Vancouver B.C. area, which has ozone problems, and the Seattle area which has been designated as maintenance by EPA for ozone. The commentors propose that the 159 tpy of CO emissions can convert to the equivalent of 16 VOC ozone potential.

Response 11: The PSD program requires an ozone analysis only if VOC emissions are greater than 100 tpy. Similarly to ethane, methane and acetone, under the clean air act CO is not considered a VOC, and hence is not an ozone precursor for permitting purposes under the PSD and NSR programs.

Comment 12: The commentors urge a 2 ppm or less VOC limit, in line with California BACT decision for the Calpine and La Paloma facilities, and elsewhere.

Response 12: A comparison of recently permitted combustion turbine projects in Washington state indicates that VOC emissions ranged from the 2.8 lbs/hr cited by the commentors for the Goldendale facility (<u>at base load</u>), to 17.5 lbs/hour at the Sumas Energy 2 Facility. It should be noted that the Goldendale facility has a VOC limit of 13.3 lbs per hour at peak load. Therefore, the BP Cogen limits (3.0 lbs/hour) are in line with minimized VOC limits.

Comment 13: A BACT analysis, including consideration of SCONOX, and XONON, should have been applied to startup and shutdown emissions. The commentors request that the number of startups be limited by a permit condition, and that startups and shutdowns be narrowly defined.

Response 13: XONON and SCONOX were not selected as BACT for this project. This means that they are not available for consideration as BACT for startup and shutdown. The permit *does* require the Project to adhere to best operation practices defined in an Operations and Maintenance Manual, including startup and shutdown scenarios (PSD Approval Condition 13). Emissions resulting from startup and shutdown were estimated and modeled. It was found that startup/shutdown emissions did not violate any regulatory air permitting standards.

Limiting the number of startups and shutdowns through a permit condition is not necessary because emissions released during startup and shutdown are counted towards the annual limits established in PSD Approval Condition 15. Approval Condition 15 has been revised to include a VOC annual limit for this purpose (14 tons per year per turbine). PSD Approval condition 14 does define startups and shutdowns narrowly.

Comment 14: The Applicant should have estimated incremental cancer risk using acceptable Risk Assessment Guidelines.

Response 14: Health impacts of Toxic Air Pollutants, including carcinogens, were assessed as required under Washington state regulation, Chapter 173-460 WAC. All toxic air pollutant emissions were found to be below the respective ASILs, and no further analysis was required.

Comment 15: The commentors state that emissions of toxics air pollutants could be greater when the facility is operated during reduced loads and startup and shutdown operation. They state that the increase in formaldehyde emission during reduced load operation was not taken into account in the modeling of toxic air emissions. They request source testing during startup and shutdown, and requiring SCONOX for control of aldehydes.

Response 15: The permit recognizes that VOC emissions can be higher during startup and shutdown, and indicates that an initial factor of 30 lbs per hour per turbine may be used for estimating VOC emissions during those periods (PSD Approval condition 14.6.3). It should be noted however, that health risks for formaldehyde are based on annual exposure. The annual emissions data used to model TAP pollutants against the respective ASILs included emissions from startup and shutdown.

NOx and CO emissions during startup and shut down will be measured and recorded by Continuous Emission Monitoring instruments. VOC emissions will be estimated according to the requirements of PSD Approval Condition 14.6.3.

The oxidation catalyst will control aldehydes with similar efficiency to CO control. This is similar to the efficiency of SCONOX.

Comment 16: The use of dry low NOx combustors increases the emissions of formaldehydes.

Response 16: Recent information released with the Combustion Turbine MACT has indicated to the contrary that dry low NOx combustors burn more efficiently than diffusion flame models.

Comment 17: Other carcinogens (dioxins, furans or hexavalent chromium) should have been included in the risk calculations.

Response 17: Established emissions factors (AP-42, and CARB ARB Speciation Manual, 1991) were used to evaluate toxics emissions from the Project. Dioxins and furans are not listed as emissions associated with combustion turbine facilities in these resources. Hexavalent Chromium was considered in the total chromium emissions (see Table 7 of the TSD).

Comment 18: The commentors indicate that a higher emission factor could have been used to estimate Acrolein emissions from the Project. Furthermore startup and shut down conditions should have been considered in this analysis.

Response 18: The commentors indicate a CARB emission rate for Acrolein of 0.0237 lb/MMscf, compared to 0.006528 lb/MMscf that was used (Source: AP-42, 0.0000064 lb/MMBTU). This translates to an emission factor that would have been 3.6 times higher than that used for steady state operations at full load. The resulting modeled concentrations of Acrolein would still be approximately half of the ASIL.

Startups and shutdowns are not expected to last 24 hours which is the averaging period for assessing impacts for Acrolein. Increased Acrolein emission would occur only until the oxidation catalyst is heated to its effective operating temperature and are expected to be within the accepted risk factors and the ASIL. Optimum startup practices combined with the oxidation catalyst will minimize emission of all organics, including Acrolein.

Comment 19: The commentors request that Toxic Air Pollutant (TAP) emissions be monitored during source tests at a variety of load conditions.

Response 19: The permit requires source testing for the most important TAP emission (formaldehyde).

Comment 20: Emissions from the emergency generator and firewater pump should be measured as part of source tests to ensure that PM10 emissions are not greater than 100 tpy. TAP emission from these units were not discussed.

Response 20: Table 1 of the TSD document identified the expected emissions from the emergency generator and firewater pump (0.09 and 0.006) tons per year respectively. PM10 emissions from the project as a whole have been clearly identified as being greater than 100 tpy (261.6 TPY).

TAP emissions from the emergency generator and the firewater pump were included in the analysis. The TSD document states: "The quantities of all TAPs known to be emitted from the turbines and duct burners, and diesel engines were estimated and screened against the small quantity emission rates in WAC 173-460." Additional information about TAP emissions is appended in Attachment 1 to this document.

Comment 21: The TSD did not indicate whether an analysis was performed to determine if cooling tower particulate emission rates lower than 0.001% were technically or economically feasible.

Response 21: The cooling tower BACT decision was based primarily on the technical analysis of what emission rate permitting and vendor guarantee information was known and available. The rate chosen as BACT was equal or lower than any listings in the EPA's RBLC database and much lower than the AP42 emission factor of 0.02% of circulating water flow. One PM10 LAER permit was found that required an emission rate of less than 0.0005% No references were found lower than that.

Comment Letter 17: William Tadlock

Comment 1: Mr William Tadlock comments that the allowable emissions from the proposed emission units seem to meet all legal requirements. The use of cogeneration steam is expected to result in emissions reductions at the existing refinery, thus improving the area's overall air quality. He recommends the issuance of the BP Cherry Point Cogeneration Project PSD/NOC Permit.

Response 1: Thank you for your comments

Comment Letter 18: Ken Cameron, Greater Vancouver Regional District

Note: Mr. Ken Cameron for the Greater Vancouver Regional District and Canadian air quality agencies Interagency Technical Review Team submits comments dated December 11, 2004, that are an edited version of comments received from the Fraser Valley Regional District, labeled "Draft, December 8, 2003" and entered as Letter 15 in these public comments.

Comment 1: The expected increase in the annual PM2.5 emissions to the Lower Fraser Valley International Airshed appears significant compared to the present overall emissions to the airshed. We recommend that the potential impacts of this project be analyzed in the context of the growing body of evidence which suggests that such increases in ambient PM2.5 concentrations would be expected to increase the likelihood of adverse health effects among some Canadian residents.

Response 1: See response to Comment Letter 14, Comment 1, and Letter 15, Comment 1.

Comment 2: A net increase in PM2.5 emissions is expected. Absent a more thorough analysis of the potential ambient concentrations of PM2.5, the PSD permit and/or Site Certification Agreement should consider requiring offsets for this parameter.

Response 2: See response to Comment letter 15, Comment 2

Comment 3: If an alternative method for measurement of particulates is approved, the PSD permit limits for PM10 should be revised accordingly.

Response 3: See response to Comment letter 15, Comment 3

Comment 4: Because SO2 and Ammonia are precursors to secondary particulate, continuous monitoring should be required for these pollutant emissions instead of annual stack testing.

Response 4: See response to Comment letter 15, Comment 4

Comment 5: The permit should set a 1-hour concentration limit of 1 ppm for SO2 and should require monitoring of fuel use consistent with the Sumas Energy 2 PSD permit.

Response 5: See response to Comment letter 15, Comment 5

Comment 6: The PSD permit does not consider greenhouse gas emissions. GHG emissions will be dealt with in the Site certification Agreement.

Response 6: See response to Comment letter 15, Comment 6

Comment 7: The PSD/NOC permit does not deal with emission reductions (offsets) resulting from removal of the refinery boilers. The permits and/or the Site Certification Agreement should include conditions for decommissioning of the refinery boilers, and amendment of the refinery permits to account for the emissions decreases.

Response 7: See response to Comment letter 15, Comment 7

Comment 8: The permit should require that conditions for startup include: a) relaxed limits for NOx, CO and VOC emissions instead of relieving limits altogether; b) revise approval conditions 14.4.1, 14.5.1 and 14.6.1 so that time limits established in condition 14.1.2 are not superceded; and c) limit startups to periods with good dispersion.

Response 8: See response to Comment letter 15, Comment 8

Comment 9: The permit should require curtailment of plant operations in the event that air quality shows signs of deterioration in the Lower Fraser valley.

Response 9: See response to Comment letter 15, Comment 9

Comment 10: Tables 3, 4 and 6 of the TSD show incorrect data for background -hour PM10 concentrations, and 1-hour CO concentrations.

Response 10: See response to Comment letter 15, Comment 10

Comment Letter 19: Steve Halpin

Comment 1: Mr. Steve Halpin requests that EFSEC pleas not let this proposed power plant fail. He is in complete support of BP's proposed power plant. The plant could possibly supply power to the Alcoa Intalco works in the future.

Response 1: Thank you for your comments.

Comment Letter 20: Marty Klix

Comment 1: Marty Klix comments that as a lifetime resident of Whatcom County, he has concluded that this could be a very good project for his community. It will be environmentally acceptable and provide jobs. He asks that the permit require local residents be hired for these jobs, and that the employer provides an apprenticeship program.

Response: Thank you for your comment. EFSEC does not have the authority to require what you requested, but those requests are now recorded,

Comment Letter 21: Stuart Pennington

Comment 1: Mr. Stuart Pennington lives about 2.5 miles from the proposed plant. He comments that he supports the plant because it will remove outdated boilers from service as well as over 70 tons of pollutants from the immediate airshed, it will help stabilize the local and regional energy supply, and it will provide new jobs and help preserve existing employment in the local area.

Response 1: Thank you for your comment.

Comment Letter 22: Franklin Eventoff

Comment 1: Mr. Franklin Eventoff comments that the Cherry Point Cogeneration Project not be allowed. Fossil fuels are finite. We are burning them rather than saving them for our children and better uses. The comment contains several more comments concerning how and why our society is misusing natural resources.

Response 1: Thank you for your comment.

Comment Letter 23: Cathy Cleveland

Comment 1. Cathy Cleveland comments that a VOC limit of 3 pounds per hour from each turbine does not equal an annual VOC emission of 43 tons/year.

Response 1: The commenter is correct. Table 4-3 of the application indicates that startup and shutdown periods will add some extra VOC emissions. These are recognized in the PSD permit Approval Condition 14.6. An annual VOC limit of 14 tons per year from each turbine has also been added to Approval Condition 15.

Comment 2: Particulate matter is permitted at 20.6 pounds per hour, which at 8,760 hours/year operation indicates emissions of 90 tons/year. The permitted annual limit is 85 tons per year.

Response 2: Table 4-3 of the application indicates that BP will not operate the cogeneration plant at maximum rate all year, and has accepted an annual limit less than the maximum possible emissions. These limits will be measured and reported, and the company has agreed to meet them.

Comment 3: Mr. Friedlob's request for $10,000 for independent citizen directed research needs to be seriously considered. She does not feel that BP will be forthright about air pollution.

Response 3: Thank you for your comment. The PSD program does not have the authority to require funds for independent citizen directed research.

Comment 4: The documents mention the road specifications for diesel, but no where in the documents or the permits does it say that BP will be required to use that type of diesel.

Response 4: PSD Approval Condition 2 specifies that onroad specification diesel shall be the only fuel for the emergency generator and fire pump. Approval Condition 1 restricts the turbines to combustion of natural gas only.

Comment 5: The commenter is concerned about ammonia emissions.

Response 5: Thank you for your comment.

Comment 6: The commenter states that the statement that PM 2.5 is not regulated is misleading. The law requires limits for PM2.5. The source cannot violate the 15.0 micrograms per cubic meter air quality standard.

Response 6: The commenter is correct that PM2.5 air quality standards must be met. A conservative analysis method is to consider all of the cogen emissions as PM2.5. Modeling results show that impacts are only a small fraction of the PM 2.5 annual standard (15ug/m3) and 24 hour standard (65ug/m3) for locations in Whatcom County. See also General Comment B at the beginning of these responses.

Comment Letter 24: Kay Schuhmacher

Comment 1. Kay Schuhmacher comments that she appreciates the benefits of the project, but the residents that live close to the refinery have to put up with the constant humming noise, grayish clouds of air emissions, odors, and visibility of chimney stacks. BP must conduct more accurate noise modeling tests. Noise could be mitigated through BP purchasing the Trillium Cherry Point Property and donating it to Whatcom County Land Trust so they can establish a Nature Preserve.

Response 1: Thank you for your comments. See General Comment A.

Comment Letter 25: M.D. Nassichuk, Environment Canada

Note: Environment Canada submitted comments developed by a technical review team comprised of representatives from the Greater Vancouver Regional District, the Fraser Valley Regional District, the B.C. Ministry of Water, Land and Air Protection, and Environment Canada. These comments, dated December 11, are identical to those submitted by the Greater Vancouver Regional District and entered into these public comments as Letter 18.

Comment 1: The expected increase in the annual PM2.5 emissions to the Lower Fraser Valley International Airshed appears significant compared to the present overall emissions to the airshed. We recommend that the potential impacts of this project be analyzed in the context of the growing body of evidence which suggests that such increases in ambient PM2.5 concentrations would be expected to increase the likelihood of adverse health effects among some Canadian residents.

Response 1: See response to Comment Letter 14, Comment 1, and Letter 15, Comment 1.

Comment 2: A net increase in PM2.5 emissions is expected. Absent a more thorough analysis of the potential ambient concentrations of PM2.5, the PSD permit and/or Site Certification Agreement should consider requiring offsets for this parameter.

Response 2: See response to Comment letter 15, Comment 2

Comment 3: If an alternative method for measurement of particulates is approved, the PSD permit limits for PM10 should be revised accordingly.

Response 3: See response to Comment letter 15, Comment 3

Comment 4: Because SO2 and Ammonia are precursors to secondary particulate, continuous monitoring should be required for these pollutant emissions instead of annual stack testing.

Response 4: See response to Comment letter 15, Comment 4

Comment 5: The permit should set a 1-hour concentration limit of 1 ppm for SO2 and should require monitoring of fuel use consistent with the Sumas Energy 2 PSD permit.

Response 5: See response to Comment letter 15, Comment 5

Comment 6: The PSD permit does not consider greenhouse gas emissions. GHG emissions will be dealt with in the Site certification Agreement.

Response 6: See response to Comment letter 15, Comment 6

Comment 7: The PSD/NOC permit does not deal with emission reductions (offsets) resulting from removal of the refinery boilers. The permits and/or the Site certification Agreement should include conditions for decommissioning of the refinery boilers, and amendment of the refinery permits to account for the emissions decreases.

Response 7: See response to Comment letter 15, Comment 7

Comment 8: The permit should require that conditions for startup include: a) relaxed limits for NOx, CO and VOC emissions instead of relieving limits altogether; b) revise approval conditions 14.4.1, 14.5.1 and 14.6.1 so that time limits established in condition 14.1.2 are not superceded; and c) limit startups to periods with good dispersion.

Response 8: See response to Comment letter 15, Comment 8

Comment 9: The permit should require curtailment of plant operations in the event that air quality shows signs of deterioration in the Lower Fraser valley.

Response 9: See response to Comment letter 15, Comment 9

Comment 10: Tables 3, 4 and 6 of the TSD show incorrect data for background -hour PM10 concentrations, and 1-hour CO concentrations.

Response 10: See response to Comment letter 15, Comment 10

Comment Letter 26: Mike Torpey, BP West Coast Products LLC

Mike Torpey of the BP Cherry Point Refinery commented that the permit's NO_X emissions limit not be changed from 2.5 ppm to 2 ppm. Several reasons were given for this. The first is that consistent compliance with 2.0 ppm has not been demonstrated. Review of CEM data from the Mystic facility in Massachusetts recently permitted at 2.0 under LAER, shows numerous fluctuations in the 2.0 - 2.5 region.

Response 1: See Letter 2, response to Comment 1 for the BACT decision and further details.

Comment 2: BP comments that emission limits should be set at levels that will allow consistent compliance. Environmental compliance is critical to BP. As a matter of corporate philosophy, even one violation of a permit limit would be one too many. BP is confident that it can consistently comply with the 2.5 ppm NO_X limit contained in the draft permit.

Response 2: Again, EFSEC appreciates BP's philosophy of full compliance with permit limits. See Response 1 for further information.

Comment 3: The Cogeneration Project significantly reduces NO_X emissions. Shutting down older utility boilers will result in a net reduction of approximately 318 tons of NOx per year.

Response: The overall reduction of NO_X emissions is acknowledged as a positive impact on the local airshed. However, because the cogeneration plant and the refinery are two different sources, this reduction cannot be introduced into the PSD permitting process. It is recognized within the Site Certification Agreement.

Comment 4: Requiring lower NO_X emissions will have environmental costs. Ammonia emissions are expected to increase, possibly 0.5 ppm or higher. This would result in approximately 11 tons per year of additional ammonia emissions.

Response 4: The possibility of increased ammonia emissions is recognized as a collateral impact of SCR utilization. Ammonia contributes to secondary $PM_{2.5}$ formation. We are not certain of the relative importance of NO_X and NH_3 contributions to aerosol nitrite formation in the Fraser Valley airshed. However, aerosol and gas-phase measurements from studies in California show that, for most samples, aerosol NO_3 formation was not limited by the availability of NH_3[11]. In Whatcom County, nearly 200 dairies generate nearly 4,128 tons per year of NH_3 based upon a) 2003 dairy inventory and b) emission factor of 87.57 lb NH_3/head – year[12].

Comment 5: Installing the larger catalyst necessary to try to achieve a 2.0 ppm NOx limit would also result in a larger pressure drop to occur in the catalyst, which would reduce the efficiency of

[11] Blanchard, Charles L., Roth, Philip M., Tanenbaum, Shelley J., Ziman, Steve D., and Seinfeld, John H. The Use of Ambient Measurements to Identify which Precursor Species Limit Aerosol Nitrate Formation; *Journal of the Air & Waste Management Association*. 2000, 50, 2073-2084.

[12] R.W. Battye, C. Overcash, and S. Fudge, 1994. *Development and Selection of Ammonia Emission Factors*. Prepared for USEPA, AREAL by EC/R Inc, Durham, North Carolina. August. Table 2-9 Recommended Ammonia Emission Factors for Animal Husbandry. http://www.epa.gov/ttn/chief/efdocs/ammonia.pdf

the facility. Lower efficiency means that more natural gas would need to be burned to produce the same amount of energy, and burning more fuel means greater SO_2, PM and greenhouse gas emissions.

Response 5: The possibility of a decrease in efficiency and its effects are noted.

Comment Letter 27: David M. Grant, Whatcom County

Comment 1: The Whatcom County Prosecuting Attorney David S. Grant comments that while Table 2 of the draft PSD/NOC suggests an incremental consumption analysis was conducted, but later testimony during the adjudicative hearing suggested otherwise. Was it performed, and was an analysis done on existing levels of NO_x, SO_2, PM_{10} and NO_2 within the impacted airshed?

Response 1. In the permit's Technical Support Document, Section 3 discusses the Ambient Air Quality Analysis. Section 3.1.2 discusses that modeling analysis for emissions show that no monitoring or modeling "significant impact level," or SIL, was exceeded by project emissions. This meant that impacts were below permitting trigger levels that require preconstruction air quality monitoring, and also cumulative impacts analysis such as a cumulative increment analysis. BP voluntarily performed an analysis estimate of existing Whatcom County and Canadian existing air quality. This is available in Exhibit 22 of the prefiled testimony, by Brian Phillips, available on the EFSEC website.

Comment 2: The commenter commented that the approval conditions include a variety of very specific compliance monitoring protocols, but the permit allows changes in these monitoring protocols without a public process.

Reply 2: PSD permit modification procedures generally require public notice when changes are made that relax permit conditions. EFSEC is sensitive to the requirement and benefits of public input. Method changes that may lead to a relaxation of permit conditions would undergo public notice.

Comment Letter 28: Doug Caldwell

Comment 1: Mr. Doug Caldwell stated "If you want me at any hearing please advise."

Response 1: Mr. Caldwell will be notified of any hearing.

Comment Letter 29: Alan Wilhite

Comment 1: Mr. Alan Wilhite commented that the BP plan appears to call for an installation that is substantially oversized and not justified by need. The BP plant could be of three smaller units. This would be a benefit for natural gas consumption and environmental impacts.

Response 1: The PSD permitting process does not provide the legal basis to restrict the size of the plant. The feasibility of building a smaller plant was evaluated in the Draft and Final Environmental Impact Statement Section 2.4.7. It was determined that a smaller project would not meet a number of criteria. A smaller project would not provide suitable steam reliability, it lacked the ability to accommodate increases in future steam demand, and it had a higher capital risk profile than the proposed configuration.

Comment Letter 30: Ann Banks

Comment 1: Ann Banks comments that "Our area is already suffering from polluted water and air. We do not need to add to the toxic mix with a co-generation plant at Cherry Point. Just once say NO."

Response 1: Thank you for your comment.

Comment Letter 31: Dale R. Petersen

Comment 1: Dale R. Petersen comments "We have no problem with the subject plant that is not far from our home, BUT we want all discharge water to have NO degrading effect on herring and eelgrass, both of which are under attack in this area.

Response 1: The air permitting program is not involved with waste and storm water discharged from the proposed plant. EFSEC has considered the impacts of water discharges to local water bodies in the Draft and Final Environmental Impact Statement, and has determined that no significant adverse environmental impacts would occur. In addition, EFSEC will condition water discharges through state and federal permits with very specific discharge and monitoring requirements.

Comment Letter 32: Mike Torpey, BP West Coast Products LLC

Note: Mike Torpey of BP provided further comments regarding the draft PSD permit and requested a further extension of the PSD comment period after meeting with EPA, EFSEC, and Ecology representatives to provide information concerning refinery operations, refinery steam demand, cogeneration plant operation, and the effects of these on NOx control. He presented that BP was opposed to the newly proposed addition of a 2.0 ppmdv NOx limit.

Comment 1: BACT limitations must be capable of being achieved in practice. Actual operating data is important in determining the appropriate emission limit. EPA has not been able to present any data indicating that a 2.0 ppm NOx limit has been consistently achieved in practice over the multi-year life of an SCR catalyst.

Response 1: In the context of BP Cogeneration's BACT analysis, a useful life of 3 years was selected for the SCR unit. Phone discussions with Shawn Konary at Mirant's Kendall Square

Station indicates no premature degradation from the SCR unit. Unit 4 is required to achieve both 2 ppm NO_X and 2 ppm NH_3. The facility started up in the third quarter of 2002. See letter 2, Response 1 for further details of the NOx BACT.

Comment 2: Consistent compliance with 2.0 ppm has not been demonstrated at operating combined cycle facilities. Review of Mystic facility in Massachusetts, and Lake Road Generating Facility in Connecticut indicated numerous exceedances of the 2.0 limit None of these facilities have been operating for more than a couple of years, while SCR catalyst live cycle is 5-6 years for natural gas service.

Response 2: The referenced units are being operated, and many more are being permitted in the United States. All new California large gas turbine permits are for either 2.5 ppmdv one hour average or 2.0 ppm three hour average. This indicates that the manufacturers and equipment suppliers do support control to this lower level of NOx emission extensively.

For further information, see response to Letter 2 - Comment 1.

Comment 3: Consistent compliance will be more difficult at the Cogeneration Project due to operational variability. Cogeneration facilities have the additional requirement of meeting the real-time energy demands of a thermal host, and must "load follow" this changing demand, resulting in continuous changes to the cogeneration unit operation that a standard power plant does not experience.

Response 3: See response to Letter 2, Comment 1 for more information.

Comment 4: A decision on the NOx emission limit should consider the overall reductions in NOx emissions resulting from the Cogeneration Project. The Cogeneration Project will enable the Refinery to decommission three of its utility boilers and minimize use of the remaining boilers. This will result in a net reduction in NOx emission of approximately 318 tons per year. Lowering the NOx limit for the Cogeneration Project could cause increases in NOx emissions through lower efficiency requiring more natural gas fuel to be combusted. A utility boiler might need to be operated more frequently to address variations in steam demand.

Response 4: See response to Letter 26, Comment 3.

Comment 5: Requiring lower NOx emissions will have other environmental costs.

Response 5: See response to Letter 26, Comments 4 and 5.

Comment Letter 33: Arne Cleveland

Comment 1: Mr. Arne Cleveland comments that he lives in Birch Bay. He is very concerned about air quality when the BP Cogen emissions are added to the pollution generated by the Puget Power plant.

Response 1: The concentration impacts of the emissions from the BP Cogen were modeled for all of Whatcom County, including Birch Bay. Their impact concentrations were lower than the regulatory trigger levels that require more modeling such as a cumulative impacts analysis of all sources. BP voluntarily determined what the total of these emissions and a conservative estimate of background pollutant concentrations would be in Whatcom County. This showed compliance with all air quality standards. See Letter 27, response to Comment 1 for more details.

Comment Letter 34: Wallace Vaux

Comment 1: Mr. Wallace Vaux comments that he has lived at Point Whitehorn in two stages from 1968 until now. He expresses his complete support for the project and urges that the authorization of construction proceed.

Response 1: Thank you for your comment.

Comment Letter 35: Steve and Helene Irving

Comment 1: Steve and Helene Irving comment that they observed plumes from the refinery today, and wonder how additional pollutants from the cogeneration plant will affect the local air quality, visibility, and local water fowl.

Response 1: For local air quality, see Letter 33, Response 1. For local water fowl impact, see responses to Letter 10.

Comment 2: The commentors comment that the plant's large 720 megawatt power output may never be needed. If BP needs 85 megawatts to run their facility, they should apply for a permit for an 85 megawatt facility.

Response 2: The PSD permitting process does not provide the legal basis to restrict the size of the plant.

Comment 3: The commentors comment that since BP indicated that it plans to sell the cogeneration plant, the company that will own and run it should apply for the permits.

Response 3: The PSD process does not provide the legal basis to restrict the sale of the plant, or decide who should apply for a permit. If the project is sold in the future, EFSEC has review procedures in place to ensure that the future owner is capable of, and required to, complying with all state conditions imposed on construction and operation of the facility.

Comment 4: The commentors comment that the Birch Bay heron colony may use the area, and that during the adjudicative proceedings two experts could not agree on what effect the plant would have on them.

Response 4: The PSD process does not have the legal authority to address this issue, but the final EIS in Section 3.7 addresses the presence of the colony and adds a statement to the Draft EIS stating “the Birch Bay great blue heron rookery is located at about 1.5 miles from the project site. WDFW management recommendations for great blue heron include a 3,280-foot buffer between heron colonies and construction activities (WDFW 2004).

Comment 5: The commentors comment that Nooksack River water use by the proposed plant is large, and salmon runs require a minimum river flow. The possible closing of the Intalco Aluminum plant may give a unique opportunity to prioritize our water draws. We should not rush to use every last drop of this precious resource without careful thought for the long term.

Comment 5: Thank you for your comment.

Comment Letter 36: Tom Pratum

Comment 1: Mr. Tom Pratum comments that he is very concerned about the environmental effects of this project. There are significant emissions of pollutants. The applicant refused to employ any significant technological controls (e.g. electrostatic separators for particulate matter).

Response 1: The permit’s Technical Support Document discusses control of particulates in Section 2.2.5. A search of information on all turbine installations in the country did not find any that used a control device such as an electrostatic filter. All natural gas fired turbines used proper combustion for particulate control. The reason is that the particulate size and concentration levels are so small that filtering devices such as bag filters and electrostatic precipitators do not work.

Comment 2: The commenter comments that adjudicative proceeding testimony made him concerned that the Birch Bay heron colony herons would be adversely be affected by the noise, air, and water pollution produced by this facility.

Response 2: See Letter 35, Response 4.

Comment 3: The commenter questions whether the region needs the plant today. The refinery only needs 12% of its power, and the region can get along without it. Why not wait and build a new power plant when it is really needed, using cleaner future technology?

Response 3: See Letter 29, Response 1.

Comment Letter 37: David M. Schmalz, Cascades Chapter, National Audubon Society

Comment 1: Mr. David M. Schmalz comments, on behalf of the North Cascades Chapter of the National Audubon Society, that it is vitally important that the effects of air pollutants on nearshore marine waters and fresh water systems, on and adjacent to the proposed project, be assessed for potential negative impacts. Bioaccumulative toxins and toxins that may concentrate in sediments are of special concern.

Response 1: See responses to Letters 10 and 12.

Comment 2: The commenter comments that it is imperative to identify and assess the combined impacts of the BP proposal with those impacts from existing industrial facilities at Cherry Point and the community of Birch Bay on salt and freshwater systems.

Response 2: The scope of the salt and fresh water impact study suggested by the commenter is beyond the legal authority of EFSEC to request for this project. See Letter 13, response 7 for cumulative impact analysis requirement discussion. The EIS does discuss many of these issues in Sections 3.4 through 3.7.

Comment Letter 38: Gary Russell

Comment 1: Mr. Gary Russell, Chief of the Whatcom County Fire District 7, commented that the cogen plant facility will allow the refinery to mothball two heater units, which removes two sources of ignition within the plant. The shutting down of these components will also lower pollutant levels.

Response 1: Thank you for your comments. See Letter 15, comment 7 concerning these boilers and the PSD process.

Comment Letter 39: John MacPherson

Comment 1: Mr. John MacPherson, of Anvil Corporation in Bellingham Washington, commented that the cogen makes the best use of natural gas energy that we know of from a heat standpoint. It will allow replacement of existing boilers, and therefore we will have less pollution. This project will produce less greenhouse gas than other methods of producing power.

Response 1: Thank you for your comments. See letter 15, comment 7 concerning boiler replacement and the PSD process.

Comment Letter 40: Kathy Berg

Comment 1: Ms. Kathy Berg, of Birch Bay, commented that BP told us that they changed their model in their favor with regards to noise because they didn't like the numbers. How can we believe their numbers now?

Response 1: See General Comment A.

Comment 2: The Great Blue Heron weighs from five to eight pounds. Why wouldn't fine particulate matter air pollution affect herons as it would similarly sized children?

Response 2: See Letter 35, Response 4.

Comment Letter 41: Patrick Alesse

Comment 1: Mr. Patrick Alesse, of Birch Bay, comments that the total tonnage of particulate matter is going to be down. That should be good, but the size of the particulate matter is going to be down, which means more of a kind of particulate matter than can get caught in your lungs. I don't want to see more of that.

Response 1. Thank you for your comment. See General Comment B for more information on fine particulate emissions.

Comment 2: Mr. Alesse comments that he can hear the sound of BP when he steps out at night except when there are good sized waves coming in Birch Bay. He chose not to accept an inherited house nearby BP because of the noise.

Response 2: Thank you for your comment. See General Comment A for more information on noise impacts.

Attachment 1: Summary of Toxic Emissions from PSD Application, Appendix E-2.